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A LOOK AT WORLD ENERGY THE ATHABASCA TAR SANDS

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A LOOK AT WORLD ENERGY

THE ATHABASCA TAR SANDS

FOREWORD

During the past several years Walwyn, Stodgell & Co. Limited has devoted considerable attention to the world energy situation. We have continued to provide a general energy overview through reports and seminars and when appropriate have sponsored visits with institutional investors to areas of current interest. In 1972, Walwyn, Stodgell visited the United Kingdom, Norway and Denmark to examine first hand North Sea petroleum developments and related European Economic community matters.

In our opinion, present attitudes and circumstances indicate that Alberta's Athabasca tar sands will increasingly become a major factor in the energy future of the world. However, the successful economic development of these resources is dependent upon many factors not the least of which are the price of crude oil and the Alberta Government policy with respect to royalties and associated industrial development. Investment strategies in the energy sector throughout the 1970's must be conducted in an environment of awareness and appreciation as to the importance the tar sands will play in meeting North America's growing energy needs.

This report on the Athabasca tar sands represents a general review of developments to date and has been prepared as background material in conjunction with a visit to Alberta and the tar sands in June 1973 sponsored by Walwyn, Stodgell.

Dennis A. Sharp

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INTRODUCTION

"In 1913 a great and potentially valuable natural resource in the northern part of the province of Alberta lay dormant and unknown while even the surface of the country was unsurveyed. Yet as a result of investigations in the field and in the laboratory, the outcome may ultimately be reflected in important commercial development. Where now the almost unbroken wilderness holds sway, industrial plants may arise and tall stacks dominate the landscape. Few will then pause to consider what these developments represent, but success will be the reward of those who had a part in the undertaking. It has been claimed that Canada's awakening north represents the greatest frontier remaining in the free world, and that the effect of its development on the future of industry and on the North American economy challenges the imagination. In due course and when necessity arises, commercial development of the Alberta bituminous sand will play its part in answering the challenge."

S.C. Ells, F.R.G.S., F.G.S. (London)[1]

At Fort McMurray, 250 miles northeast of Edmonton, Alberta the important commercial development which the late Sidney Ells foresaw is quickly becoming a reality. Although Mr. Ells might be equally impressed with the present exploration ventures into Canada's far northern reaches of the Mackenzie Delta and the Arctic Islands, there can be little question that the development of Alberta's tar sands will increasingly become a major factor in the energy future of the world. In the 1970's Athabasca, the Cree Indian word meaning *"where the are weeds"*, has now become synonymous with *"where there is oil"*.

[1] 1962; Recollection of the Development of the Athabasca Oil Sands; Department of Energy, Mines and Resources, Mines Branch IC 139.

HISTORY

In 1778, Peter Pond, a fur-trader and explorer of the North West Company, was the first white man to observe the oil sands when he paddled down the Athabasca River and saw Indians caulking their canoes, with tarry oil that oozed from the river banks. At the junction of the Athabasca and Clearwater Rivers, Peter Pond established the "Fort of the Forks", now Fort McMurray. Almost a century passed before any significant notice was taken of this natural phenomenon until 1875 when the Federal government initiated a survey of the region by the Geographical Society of Canada. In 1884, R. Bell and in 1891, R. G. McConnell published through the Geological Survey of Canada the original works on the Athabasca tar sands. McConnell reported that the *"tar sands evidence an up-welling of petroleum to the surface unequalled elsewhere in the world"*.

When Sidney Ells, a young engineer, first led a party from the Department of Mines in Ottawa, some 1,250 square miles of the Athabasca country were surveyed for topographic maps under the most adverse conditions. In the fall of 1913 Ells' crew brought out the first shipment of soil samples, dragging a heavily loaded 40-foot scow up 240 miles of rapids and fast water. In the following year, a large shipment of 1,400 sacks was hauled by 23 teams of horses through the snow in the bitter cold of January and February. Later, Sidney Ells made laboratory tests, conducted several mining projects and carried out the first commercial application of the Athabasca bitumen for paving streets in Edmonton.

With the advent of the motor car, paving was the most important use for bitumen at the time. A second plant was constructed and operated at Jasper Park, and a third plant of a mobile nature was built on a railway flat car. In 1915, Ells conducted tests at the Mellon Institute in Pittsburgh to determine the best method of separating the oil from the sand. His conclusion was that the use of flotation cells offered the most promising possibilities for low cost and efficient

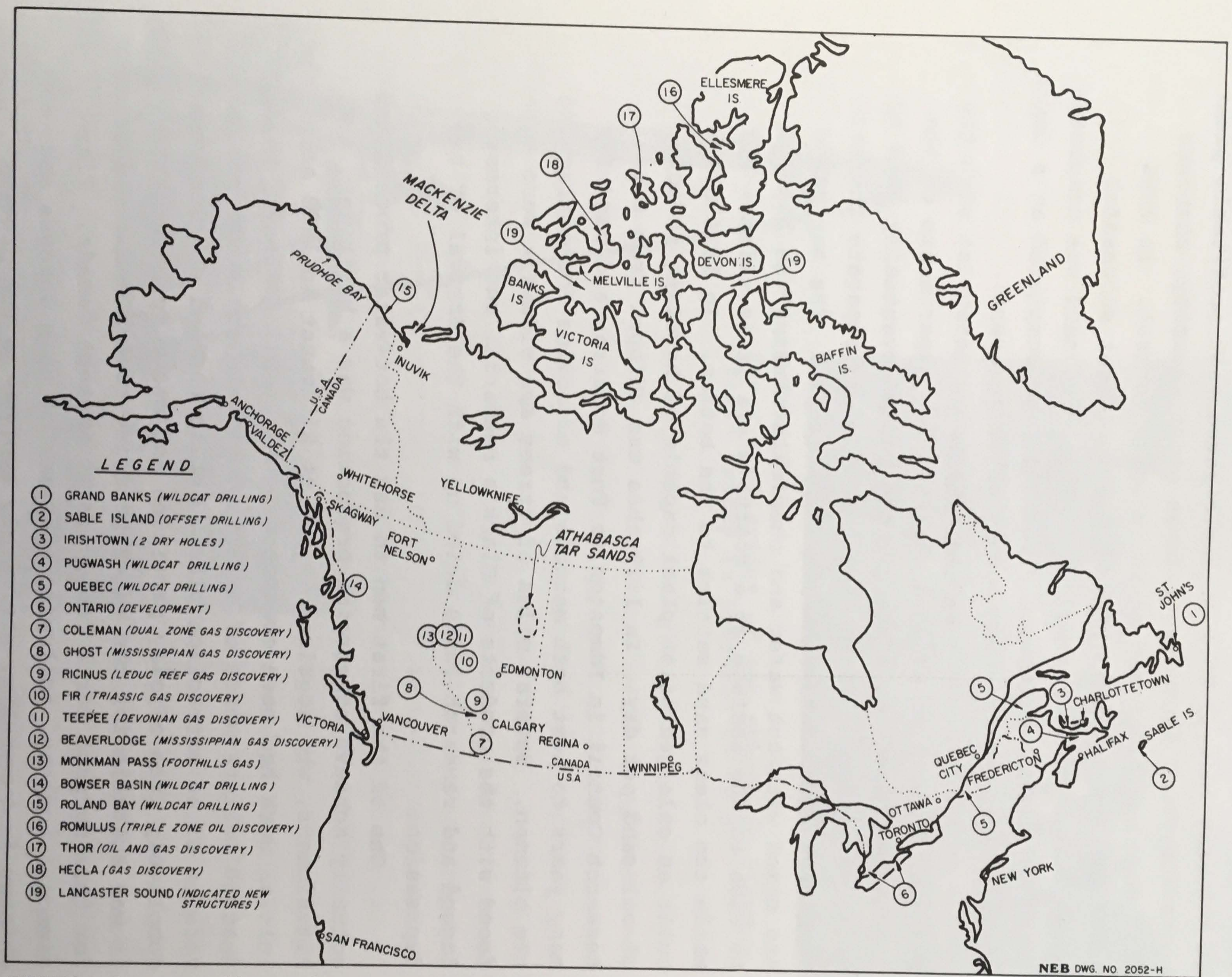

FIGURE 1: *Canadian oil and gas developments - 1972*

recovery. With slight variations, this is the method in use at McMurray today. He also anticipated that profitable plant operation would depend on a large plant capacity, combined with able technical and administrative control. In 1926 under the supervision of Dr. Ells, the first successful attempt ever made to core drill bituminous sand was completed using cable tool equipment. The well was completed at a depth of 237 feet with a core recovery of 96 per cent.

In 1923 Dr. Karl A. Clark, a young scientist with the Research Council of Alberta, started his experiments on the "hot-water flotation process", the method eventually used by Great Canadian Oil Sands Limited (GCOS) to separate the bitumen from sand. In principle it is simple. The tar sands are mixed with hot water and chemicals causing the bitumen to rise to the surface as a froth, where it is skimmed off, while the clean sand settles to the bottom. In 1924 Clark built an enlarged pilot plant capable of handling 60 tons of oil sand per day. In 1929 this was shipped from the Research Council in Edmonton to Fort McMurray and used for many years to test both methods and economics for extracting the bitumen. Several miles of street and sidewalk were surfaced with the products of Clark's research, but interest lagged and research funds dried up with the arrival of the depression.

One of the first men to use the hot-water process and actually achieve commercial production was a Maritimer, R.C. Fitzsimmons, who acquired leases at Bitumount in 1923 after the initial work had been conducted by Alcan Oil Company. With just 50 dollars worth of material, Fitzsimmons built his own version of an extraction plant. While the end product wasn't completely free of clay particles and other foreign matter, it was suitable for the water-proofing of roofs and was sold for this purpose for a few years in western Canada. Fitzsimmons' company, following a series of name changes and changes in ownership, ultimately evolved to the present

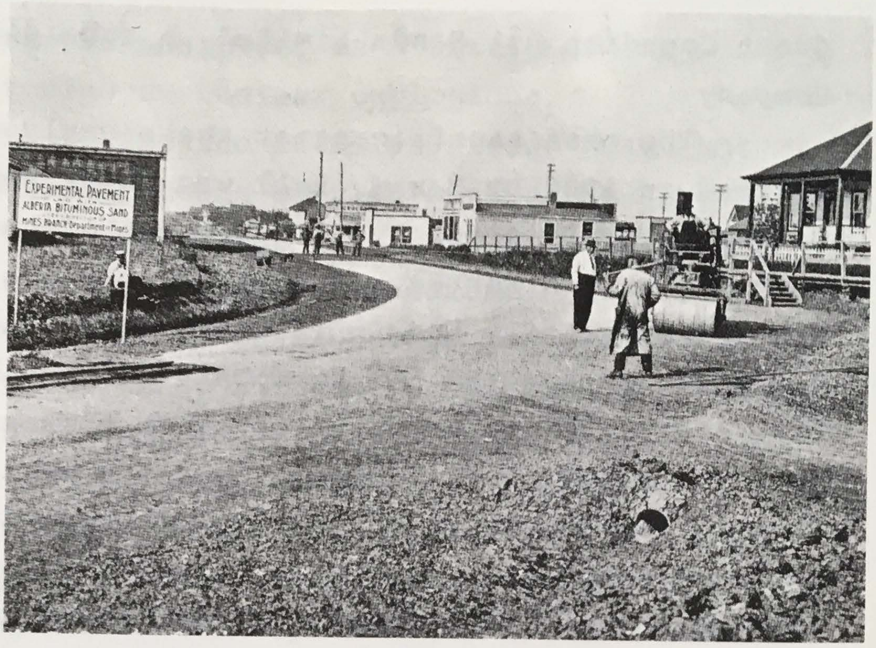

FIGURE 2:
First application of the Athabasca bitumen to street paving in Edmonton in 1915

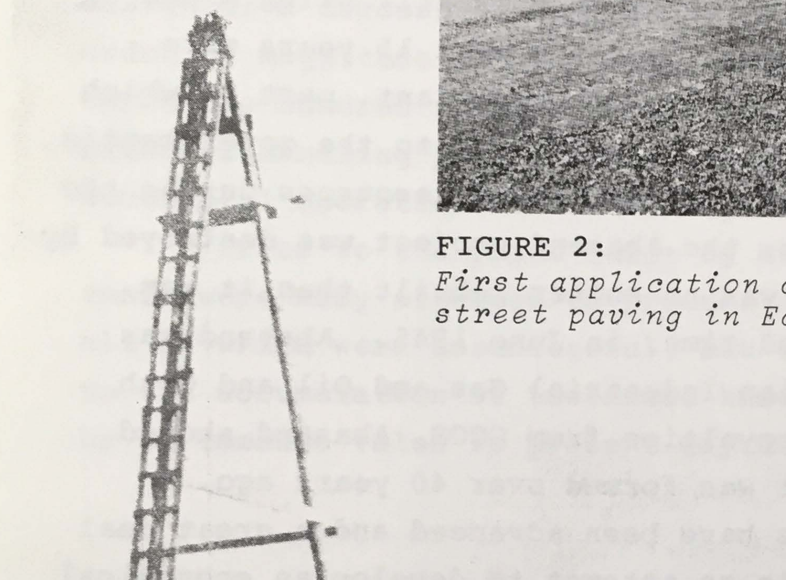

FIGURE 3: *Cable tool rig used to obtain tar sands core in 1926*

Great Canadian Oil Sands Limited, a subsidiary of Sun Oil Company.

The most significant of these early operations was started in 1930 by Max W. Ball who later became Director of the Oil and Gas Division, U.S. Department of the Interior. Ball formed Canadian Northern Oil Sands Products Ltd., later called Abasand Oils Ltd., and in 1932 acquired what appeared to be desirable acreage in the Steepbank and the Mildred Lake-Ruth Lake areas, the latter area which is presently being mined by Great Canadian Oil Sands. Over the next 15 years more that $2 million was spent on the Abasand plant, part of which was provided by the federal government due to the government's eagerness to develop additional petroleum resources during the war. Plagued by bad luck, the Abasand project was destroyed by fire in 1941. The plant was no sooner rebuilt than it was destroyed by fire a second time, in June 1945. Abasand was later purchased by Canadian Industrial Gas and Oil and with the initial payments of royalties from GCOS, Abasand showed its first income since it was formed over 40 years ago.

Numerous proposals have been advanced and a great deal of research carried out in an attempt to develop an economical method of extracting the bitumen from the Athabasca tar sands. Some of the more popular concepts described in recent literature include: the cold water process, fluidized solids technique, in-situ steam drive, in-situ combustion, sand reduction method, anhydrous process, in-situ recovery by nuclear explosion, and the hot water process.

Possibly the most ambitious of all the various efforts was Project Oilsand, a proposed experiment in the peaceful use of nuclear energy as an aid in producing oil from the tar sands. Plans were carefully laid in 1958 and 1959 by Richfield Oil Corporation for a nine kiloton nuclear explosion to be set off at a depth of 1,250 feet at a site 64 miles south of Fort McMurray. A special technical committee was established by the Alberta and federal governments and approval was recommended.

In the end, the test was postponed as a result of the international moratorium on nuclear explosions.

The decade following the 1948-1949 large scale hot water process feasibility tests carried out by the Alberta Research Council at Bitumount was particularly significant in the history of tar sands plant development. It was during this period that would-be producers realized that size was probably the most significant consideration in the design of a successful commercial plant. In some cases the order of magnitude in planning new plants was revised upwards one hundred fold. In addition, it was realized that material handling problems had a far greater effect on successful operations than did any other technical factor.

Prior to the plant built by Great Canadian Oil Sands, there were many attempts to produce oil on a commercial basis, all of which were unsuccessful, but in total each contributed to the accumulation of technical knowledge which is proving to be of immense value in present day design considerations.

DESCRIPTION OF DEPOSIT

The Athabasca tar sands contains a vast accumulation of heavy viscous oil. Excluding several similar but smaller deposits in the same general area, the main body of the Athabasca sands covers an area of approximately 9,000 square miles, almost twice the areal extent of Lake Ontario, and contains over 625 billion barrels of oil in place. Using mining methods presently considered economic, employing an overburden to tar sands ratio of 1:1 and a minimum percentage by weight of 5% bitumen, estimated proved reserves are 38 billion barrels of bitumen or 26.6 billion barrels of synthetic crude oil. Approximately two-thirds of a barrel of bitumen would be extracted from each ton of sand mined. A further 250 billion barrels are potentially recoverable by in-situ thermal stimulation. The most recent Alberta Resources

Conservation Board estimates are set forth in Appendix A.

The bitumen is accumulated in the McMurray Formation of Cretaceous age although locally it extends into the overlying Clearwater Formation. The McMurray Formation consists predominantly of quartz grains with clay comprising about 8 per cent of the mineral matter present. Except for the localized outcrop areas associated with the Athabasca River and its tributaries where saturation thicknesses range up to 150 feet, the evaluated tar sands area is covered by overburden. Much of the area is marginal boreal forest and muskeg with the overburden generally consisting of a thin layer of soil and glacial drift. The beds in general slope to the southwest, eventually becoming overlain by sand and shale deposits up to 2,000 feet in thickness. Although outcrops along the Athabasca River are representative of the overall deposit, the thickness of the oil bearing section varies greatly over the area. In some cases it ranges up to as much as 400 feet while in others it is as little as a few feet. Oil content of the Athabasca deposit varies laterally due to variations in both the gross thickness of the deposit and the degree to which the tar sands are saturated. Variations in the thickness of the deposit are caused by irregularities in the relief of the underlying Paleozoic surface. The western part of the Athabasca deposit thins and pinches out against the ascending Paleozoic surface whereas elsewhere a reduction in thickness has occurred, due to a regional Paleozoic high about 40 miles in length. Less obvious are the local and abrupt thickness variations caused by the much smaller Paleozoic remnants within the areal limits of the Athabasca deposit. Variations in the thickness of a deposit are also caused by the lateral transition of the lower or upper tar sands to water bearing sands or tight sandstone, siltstone or shale, although abrupt lateral changes to shale are most common.

McMurray Formation porosities are often as high as 35%. Between 55% and 89% of the available pore space is occupied by oil with 1% to 30% being taken up by formation water. For the

most part sand grains are water-wet -- a characteristic which allows separation by water washing. The raw oil is a black, naphthenic base hydrocarbon which has a specific gravity of about 1.01 and a viscosity which ranges from 3,000 to several hundred thousand poise at 60 degrees Fahrenheit. The sulphur content of the oil is high for most areas and ranges from 4% to 6%. In addition, the oil has a relatively high nickel-vanadium porphyrin content. Overall, the Athabasca oil does not present an impressive list of the most desirable qualities yet many of its poor qualities are offset by its above average cracking and hydrogenation characteristics.

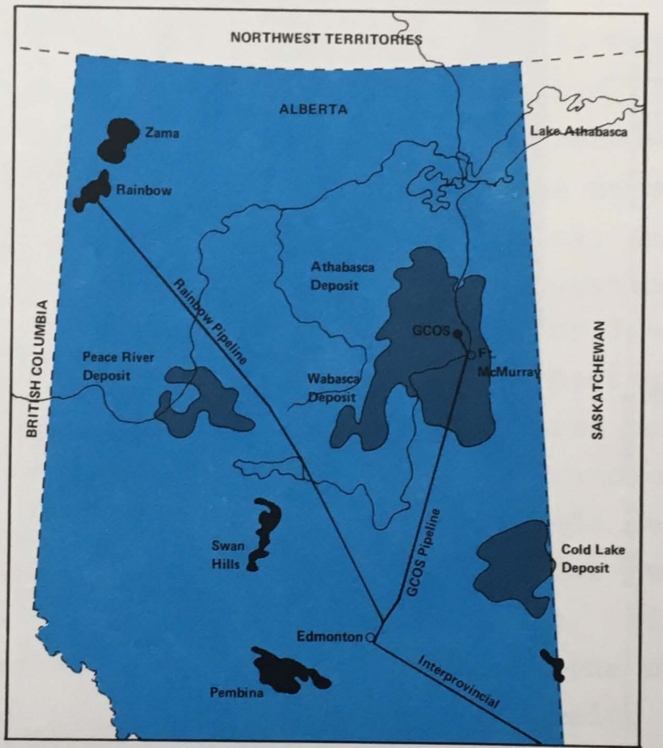

FIGURE 4: *Location of Alberta tar sands deposits*

The degree of saturation of the oil zone is exceedingly variable throughout the Athabasca area. When being described, oil saturation is usually expressed as a weight percentage with actual measurements varying from the 18% to 20% range down to zero. Those sands containing 10% or more oil by weight are considered good with definite recoverable potential. Expressed

in different terms, good areas run as high as 250,000 barrels per acre with the average at about 100,000 barrels per acre.

Oil saturations are variable in magnitude resulting in a heterogeneous distribution of the oil in the deposits. The saturation for successive 1 foot intervals are commonly ob-

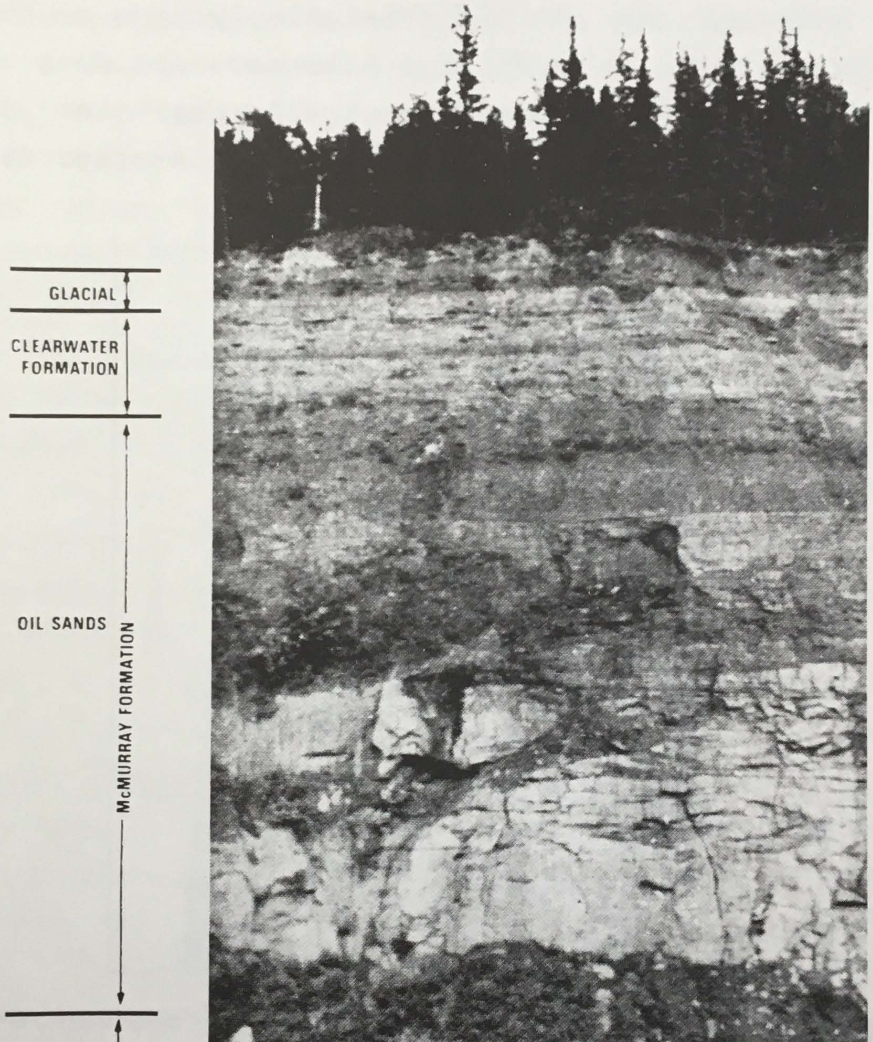

FIGURE 5: *McMurray Formation outcrop along Athabasca River showing dark layers of tar sands*

served to vary from an oil saturation of up to 20% by weight to the minimum saturation of less than 1%. These vertical variations are for the main part attributed to the sudden occurrence of shale partings in the intervals for which the lower oil saturations were measured. As a result of saturation variations, the total oil content of the deposit has been observed to decrease by as much as two-thirds or more over horizontal distances of only one-half mile even though the thickness of the gross interval remains relatively uniform. Conversely, oil saturations have been observed to remain relatively constant over distances of about 10 miles in certain parts of the Athabasca deposit.

Although originally, an overburden to tar sands ratio of 3.5:1 was considered economically feasible, economic viability by tested mining methods is now based upon those areas having an overburden thickness in the order of 150 feet, saturated beds between 100 to 200 feet thick, and tar sands containing 5% or more by weight of oil saturation. While saturation limits have not been established for in-situ thermal stimulation recovery methods, those areas having in excess of 350 feet of overburden are usually considered most amenable for the application of such methods. Thus by recovery method and overburden thickness, the Athabasca tar sands can be divided into two distinct areas: one prospective for recovery by mining and the other by thermal stimulation. Although considerable experimentation and testing has gone on in both, the mining area is the only one currently being produced. It has been estimated that 80% of the oil reserves are located in 40% of the total volume of the oil bearing sediments. Under such varying conditions some areas become highly prospective for oil production, while others are beyond the practical limits of recoverability.

Recovery factors for the Athabasca tar sands have been generally developed within acceptable limits by both government and industry. On the basis of recovery factors established by

the Alberta Board, recovery of raw oil sand oil ranges from 83% where the range of overburden is from 0 to 50 feet to less than 50% where the overburden is greater than 250 feet. Taking into account the recovery of upgraded synthetic crude oil, 30° to 37° API at 60° Fahrenheit, the recovery factor is further decreased to 60% and 40% respectively on the basis that approximately 30% of the oil generated is required as fuel for the extraction and refining processes.

APPLICATIONS FOR SYNTHETIC CRUDE OIL PRODUCTION

The first application for approval of a commercial project to recover synthetic crude oil from the Athabasca tar sands was made by Great Canadian Oil Sands Limited in March 1960. After the Alberta Board found the first proposal deficient in some respects, the revised scheme was approved in September 1962 and provided for the production of 31,500 barrels of synthetic crude oil per day to commence in 1966. This was amended in 1964 to 45,000 barrels and more recently in early 1973, GCOS requested that the level of production be increased to 65,000 barrels of synthetic crude oil per day. 1972 daily production averaged 51,000 barrels.

The second and third applications made for the recovery of oil on a commercial basis from the tar sands were made by Cities Service Athabasca Inc. who requested approval for the production of 100,000 barrels per day of synthetic crude oil commencing in 1969 using surface mining and a hot water separation process and from Shell Canada who requested approval for the production of 130,000 barrels of raw oil per day, equivalent to 96,854 per day of synthetic crude oil, commencing in 1969 using an in-situ thermal recovery process developed by Shell over a period of years. The raw oil recovered would be dehydrated and piped to Edmonton for final processing. The Cities Service Athabasca Inc. application was submitted on

behalf of Cities Service, Imperial Oil Limited, Richfield Oil Corporation and Royalite Oil Company Limited. This group was later incorporated as Syncrude Canada Ltd.[1] The initial Syncrude application was submitted in May 1962 and the application was heard in January 1963. The Shell application was submitted to the Alberta Board in September 1962 and was heard in February of the following year.

At the time of these two applications Cities Service estimated total capital requirements of the project excluding the cost of initial research would be in the order of $356 million. Shell estimated the maximum cash requirements of their project would be approximately $260 million.

In October 1962 following approval of the GCOS application the then Premier E.C. Manning, on behalf of the Alberta Government, issued a statement with respect to tar sands development. In addition to providing guidelines, the Government clearly stated it had a responsibility to regulate the timing and the extent of tar sands production to protect the interests of the public as the owners of this resource and to ensure that the position of conventional oil production in Alberta was not jeopardized by the loss of already limited markets to a new source of supply. It was the Government's stated policy that an opportunity would be provided for the orderly development of the tar sands within the limits dictated by the Government's responsibility to the public interest in preserving the stability of conventional oil development and the necessary incentive to ensure its continued growth. Where such production from the tar sands could be established as to be able to reach markets clearly beyond present or foreseeable reach of Alberta's conventional industry, there would be no need to restrict the rate of production from the tar sands. Clearly, at that time it was the Government's intention to ensure the conventional oil industry a rate of production and a share of available markets in excess

[1] As presently constituded Syncrude Canada Ltd. is owned by Cities Service, Imperial Oil and Atlantic Richfield 30% each and Gulf Oil 10%.

of what then currently prevailed and also to ensure that a reasonable share of future increased markets would be available to conventionally produced oil. This would still give scope for the orderly development of the tar sands under a regulated program that would protect the public interest by preventing detrimental dislocations in the provincial economy.

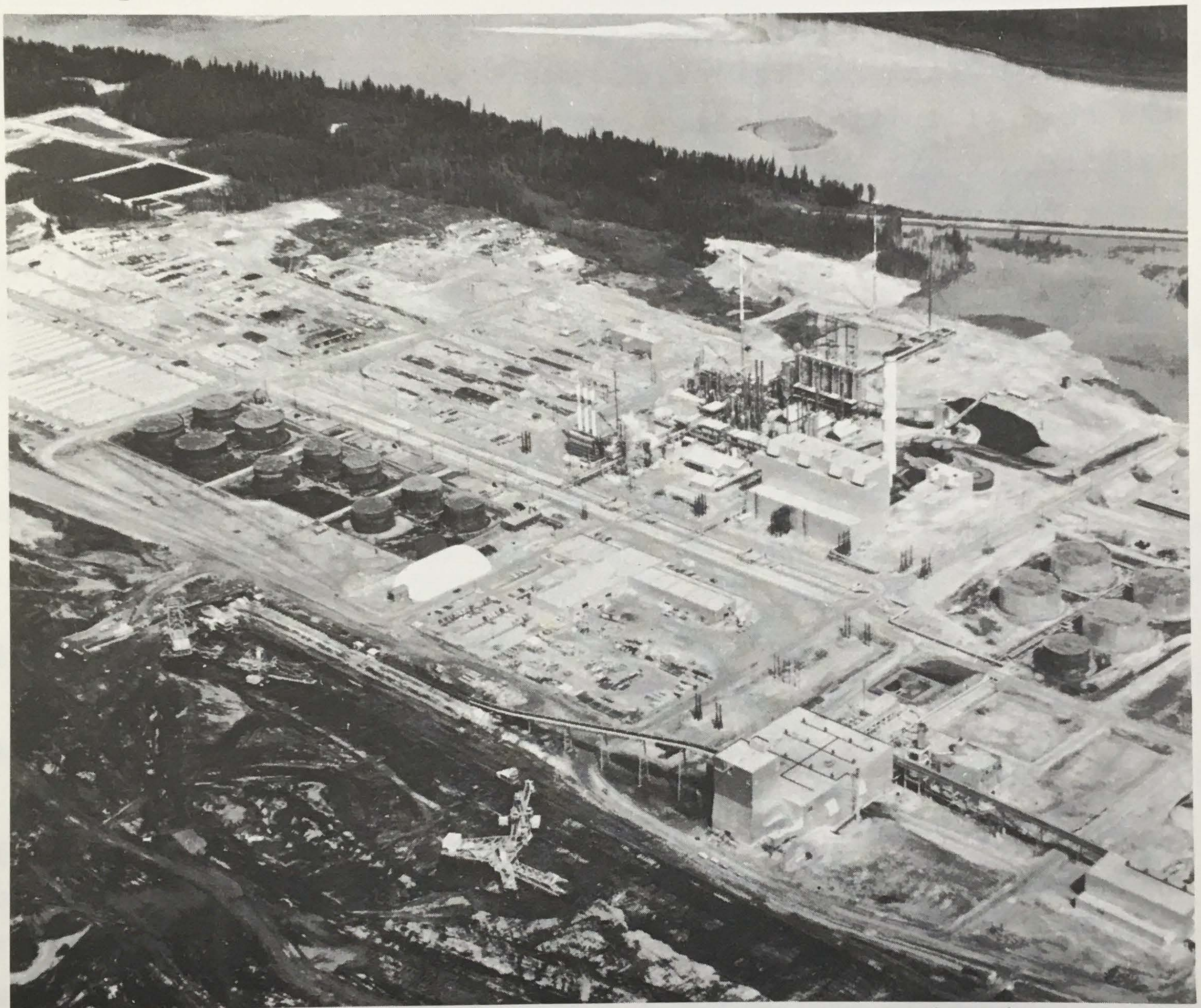

FIGURE 6: *Aerial view of Great Canadian Oil Sands plant 20 miles north of Fort McMurray along the Athabasca River*

Taking into account stated Government policy, the Board found it necessary to refuse both applications. In reaching its decision with respect to the Cities Service and Shell applications, the Board found the applications to be technically sound but on the basis of the impact on the

market for conventionally produced crude oil, found the probable impact of the production proposed by the applicants to be beyond the 5 per cent limit of the crude oil market available to synthetic oil. This decision was prefaced having regard to the existing approval to Great Canadian Oil Sands for the production of 31,500 barrels per day of synthetic crude oil from the tar sands. On the basis of the ultimate desirability of authorizing further production from the tar sands the Board deferred its final consideration of both applications and permitted the applicants to provide evidence to the Board prior to December 31, 1968 that the tar sands projects as proposed would not in fact be contrary to Government policy as presently interpreted.

During the interval between the original decision and 1968, Shell Canada decided not pursue its application further. However, as provided for by the Alberta Board disposition in its 1963 decision, Syncrude applied in 1968 for approval of its application, although the later proposal involved certain technical changes from the 1962 application. The Board agreed that significant improvement had been made in each of the major process steps and found that there were no technical feasibility considerations that should stand in the way of approval of the project.

Once again the Board refused the application on the basis that substantial uncertainties existed with respect to the probable magnitude and rate of development of the recent Alaskan discovery at Prudhoe Bay. Syncrude subsequently made application in February 1969 to the Alberta Government, submitting that an additional hearing would not be of decisive assistance to the Board since reliable forecasts of Alaskan production rates and the probable effect on U.S. markets and Canadian exports would have to be based upon nothing more than a tentative estimate of reserves. Definitive evaluations of production and transportation costs and market opportunity would be required but these evaluations would only evolve over a period of years and meaningful

data would not be available over the short term.

After further representation, in May 1969 Syncrude once again appeared before the Board and presented an amended application. In the matter of the marketing plan and on the evidence supplied by the applicants, the Board was satisfied that the probabilities favoured the removal of Government controls on the export of Canadian oil to the United States by about 1977 and therefore that the markets proposed for the synthetic crude oil by the Syncrude group would meet the net increase requirements of the tar sands development policy. The Board granted approval to the recovery in each calendar year of 18,250,000 barrels of synthetic crude oil, 9,125,000 barrels of specialty oils and 1,825,000 barrels of naphtha. Based on a subsequent application by Syncrude to the Board in September 1971, the amount of synthetic crude to be produced was revised upwards to 125,000 barrels per day. In addition, slight modifications were made in the mining schemes to improve the system. Continued opposition to increased production from the oil sands centred around the possible lack of pipeline capacity from Alberta to transport the production of conventional crude oil and the increased volumes of synthetic crude but the Board found such claims to be unsubstantiated in view of Interprovincial Pipelines' projection. The overall expected recovery of the revised scheme would be 62%, slightly higher than previously anticipated. Syncrude must now advise the Alberta Government not later than August 31, 1973, if it intends to proceed.

COMMERCIAL DEVELOPMENT

Great Canadian Oil Sands Limited

Based on the new concepts in the economy of scale, Great Canadian Oil Sands engineered and built the first major commercial oil sands production plant. Initial testing and construction was started in 1962 and the plant came on stream in September 1967. It was designed to produce 45,000 barrels per calendar day of 36 degree API gravity synthetic sweet crude. The plant, based on a four stage sequence of mining, material handling, extraction, and heavy oil upgrading, required a peak construction force in excess of 2,000 workmen.

FIGURE 7: *One of two large bucket-wheel excavators used by GCOS to mine tar sands*

The engineers of GCOS and Canadian Bechtel Ltd., prime contractors on the project, faced a complexity of problems. In addition to the plant itself, the engineers had to build a 20-mile road to the site, construct a $3.3 million steel truss bridge spanning the Athabasca River near McMurray, and lay a 266-mile

pipeline to Edmonton.

In the area now being mined, the overburden, averages approximately 40 feet in thickness. Orginally, overburden was removed using fourteen 32 cubic yard tandem engine scrapers but removal procedures have been modified with the acquisition of a fleet of trucks and front-end loaders to replace the leased scrapers. The oil-saturated sands beneath lease No. 86 average 150 feet in thickness and are mined by giant bucket-wheel excavators specially designed in Germany each with a design capacity of up to 100,000 tons of sand daily. One wheel operates from the pit floor and the other from a bench at about the 75 foot elevation mark. Isolated pockets of oil sands, which are not readily accessible to mining by the large bucket-wheels are recovered using a small bucket-wheel purchased in 1971 and the front-end loaders. Provision is also made for the overburden removal fleet to supplement the mining wheels during periods of routine maintenance, when mechanical trouble develops or when especially difficult formation problems are encountered.

As the oil sand is mined, the material is loaded on a 72-inch wide conveyor belt and transported to the extraction plant at a velocity of approximately 1,000 feet per minute. The belt unloads directly into bins capable of handling in excess of 10,000 tons of feed material. The surge bins discharge onto apron feeders which in turn load the conveyors feeding four parallel horizontal slurrying drums. In these drums, both steam and hot water are introduced in amounts sufficient to create a soft watery pulp containing appreciable amounts of entrapped air. The slurry is pumped to a hot water extraction system where oil is removed in the form of a froth and then diluted with naphtha. The diluted oil in this stream is then passed through a centrifuge system where water and unwanted solids are removed. The dilutent is then recovered. Sand from the system is discharged into a separate stream.

From the centrifuge dilutent recovery system, the oil is fed through heaters to six parallel delayed coking drums.

PROCESS FLOW

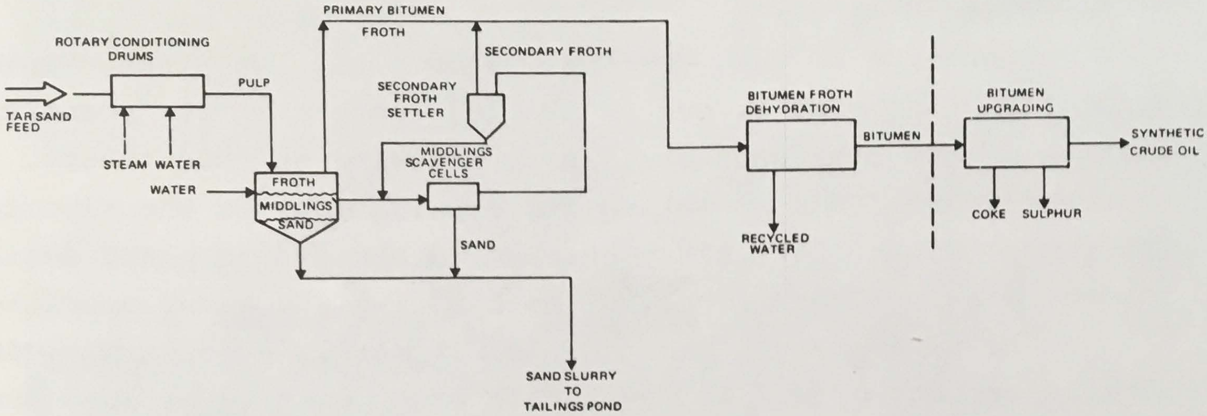

FIGURE 8: *Hot water process schematic flow diagram*

These coking drums are some of the world's largest measuring 26 feet in diameter by 95 feet high, in which 3,000 tons of coke are produced daily. Coke produced in these units is collected and after being pulverized is used for plant fuel. The overhead product is separated into three streams: naphtha, kerosine, and a wide range of heavy gas oil. Each of the three overhead streams requires different amounts of hydrogen to meet desired specifications and therefore are individually hydro-treated. After hydrogenation the three streams are blended to form the product called synthetic crude. This material, a full range distillate product containing gasoline, kerosine naphtha, butanes, pentanes and pentanes plus, is light amber in color, has an API gravity rating of approximately 36° and a boiling range of 210° Fahrenheit. Sulphur content is exceptionally low.

Also required, along with the mining, material handling and process units, are supplementary plants sufficient in size

to supply 60 million cubic feet per stream day of hydrogen, to produce 300 tons per day of sulphur and to supply 70,000 KVA of electrical power.

Syncrude Canada Limited

Operation of the first tar sands plant has strengthened the conclusion that size is one of the key factors in the commercialization of the Athabasca tar sands. Working on this theory, Syncrude Canada Ltd. in making its applications to the Alberta Government since 1962, has continued to modify its plant design to ensure an optiumum level for both mining and plant operation.

The plant is now designed to ultimately produce 125,000 barrels per day of 30° API synthetic crude oil and related products with initial output of approximately 104,500 barrels per day. In principle the Syncrude plant is similar to the GCOS plant but in conceptual detail it entails considerable modification. In place of the bucket-wheels and front-end loaders employed in the mining scheme by GCOS, Syncrude plans to utilize large draglines to accomplish both removal of overburden and mining of the tar sand. Four machines will be employed, each equipped with buckets having a capacity of about 80 cubic yards. The maximum digging depth of the machines is estimated at 210 feet which exceeds the maximum depth of 190 feet of tar sands encountered on the lease to date. In this operation, direct dumping of the overburden into the mined out pit will be possible whereas in the case of the GCOS plant, overburden must be hauled by truck to a distant unloading point.

Using the dragline scheme, no equipment other than pumps will be required in the bottom of the pit. Surface and formation drainage requirements will be minimized and any special diking within the pit for extraction plant sand tailings disposal will be eliminated. In the initial stages of operation, tailings will be disposed into a retention pond and as mining continues the tailings will be hydraulically deposited on the windrows of overburden in the mined-out area. Of particular

FIGURE 9: *Dragline used by Syncrude to remove overburden and mine tar sands*

advantage in the Syncrude scheme will be the elimination of the necessity for extensive overburden removal in advance of tar sand mining, thus frost penetration of the tar sand surface can be minimized during subzero weather.

The dragline will operate from the surface and after exposing a shelf of tar sand will leave the overburden face at an angle of 45 degrees and proceed to mine through the tar sands establishing a face of greater than 65 degrees. It will be possible to operate effectively to combined overburden and tar sands depths of 200 feet - the maximum expected during the first twenty years of operation. The mined tar sand will be placed in a reclaim pile on the surface paralleling the main mining face.

A reclaim wheel feeding a short belt conveyor will be utilized in conjunction with each dragline to load simultaneously the main bulk of the stockpiled sand into railway hopper cars. Five electrically-powered trains and one complete spare unit, each consisting of one 200 ton locomotive and fourteen 100 ton capacity cars, will be employed. This will allow each train 60 minutes to make one round trip with separate trains arriving at the dump station every twelve minutes.

The Syncrude design should offer several advantages in overall materials handling and several steps have been introduced to improve the uniform sizing of material to ensure high operating efficiency. In the mixing drum, steam and hot water are added to the tar sand to create an air saturated slurry. A single drum, with a diameter of 22.5 feet and a length of 160 feet, has been designed to handle 7,250 tons of feed material per hour - the entire through-put of the plant when operating at design capacity. The concept of size was pushed to its maximum in the design of the mixing drum. This was possible because the mixing operation is simple and straightforward. With similar equipment already in operation in related industries, service factors were readily calculated creating confidence in the scheme. By eliminating multiple equipment, many operating efficiencies are expected along with lower space requirements.

The hot water extraction cells, to which the slurry is fed, are similar to those used by GCOS. As in the GCOS process, Syncrude will dilute the froth with naphtha and centrifuge it to remove water and solids. In the primary conversion step, the cleaned bitumen will be fed to fluid coking units where thermal cracking of the heavier fractions takes place. The overhead stream will be broken into two separate streams: naphtha and light and heavy gas oil. Each stream will be individually hydrotreated. The two hydrotreated streams will be blended to make the specification synthetic crude or related products. It will be possible to exercise some flex-

ibility in the degree of hydrotreating employed in this part of the process. By the utilization of such control together with the possibility of taking advantage of a variable ratio in blending the two hydrotreated streams, optimum feed-stock requirements of individual refineries can be met. In addition, these streams could be blended to form high quality fuel oil to meet the most stringent pollution regulations. Whether it be synthetic crude or specialty oils, Syncrude has designed its plant to enter North American markets in competition with conventionally produced oil.

Associated with the basic plant will be a 115 million standard cubic foot per stream day hydrogen plant and a 450 ton per day sulphur plant. A separate utility plant will furnish 195 megawatts of electrical power, 1.4 million pounds of oil process steam per hour and 900 gallons of treated water per minute.

Shell Canada Limited - In-Situ Recovery Method

It has generally been acknowledged that the low-cost strip mining of the Athabasca tar sands is restricted to areas of low overburden and that the greater quantity of oil can not be economically produced by this method. Because of this, Shell Canada decided to concentrate its research on an in-situ recovery method which would be applicable to the greater portion of the deposit.

The Athabasca oil is sufficiently viscous that primary and secondary recovery methods common to the petroleum industry are not useful for producing the bitumen. In order to produce the oil without moving the sand it is necessary to make the oil flow.

Shell's steam and chemical drive method requires that injection and production wells be drilled in regular patterns such as a five-spot pattern. The wells are opened to the tar sand formation and a horizontal disc-like fracture propagated connecting sets of injectors to producers. Steam and aqueous

alkaline solutions are then injected into the fracture. The oil adjacent to the fracture is heated, and is then emulsified and driven to the producer as an oil-in-water emulsion.

Shell Canada commenced its first geological survey of the Athabasca tar sands in 1946 and since that time has made laboratory and field investigations on in-situ methods for recovery of the oil. In 1957, on Bituminous Sand Lease No. 26, Shell made its first field tests on an in-situ method of recovering the oil from the tar sands using the injection of aqueous alkaline solutions of a synthetic detergent which were capable of wetting, emulsifying and suspending the oil. After further testing, Shell established in 1960 a highly instrumented and extensive pilot program combining the use of steam and alkaline solutions. Considerable experimentation led Shell to the conclusion that the in-situ method was in fact feasible. Shell indicated that for successful operation some overburden was necessary but that successful experiments had been conducted with overburdens as thin as 150 feet.

Based on laboratory research, theoretical work, and data established in the field experiments conducted between 1960 and 1962, Shell reported a recovery efficiency of at least 50 per cent and possibly as high as 70 per cent of the oil in place in the clean McMurray sands using this recovery process.

The production data show that during the final period of the experimental program carried out on Lease No. 13, long after steam condensate appeared in the producing well, there was no significant decrease in either the rate of oil production or in the oil-to-water ratio. Shell concluded that by continuing the experiment, greater depletion could have been achieved, and that recovery efficiency in the area swept would finally equal or better the greatest displacement efficiency measured. This was 74 per cent of the initial oil in place. Combining the displacement efficiency of at least 70 per cent with a sweep efficiency ranging from 50 to 70 per cent is obtained. Recovery efficiency of this magnitude is in general far greater

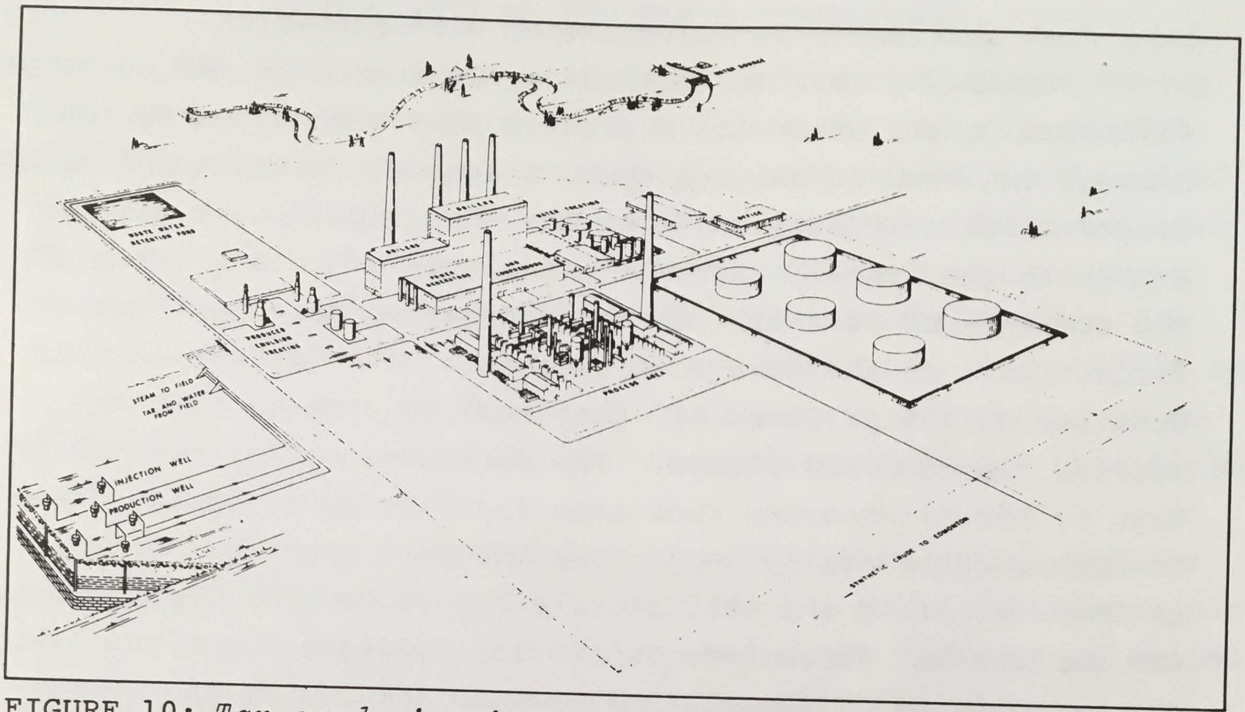

FIGURE 10: *Tar sands in-situ steam drive project*

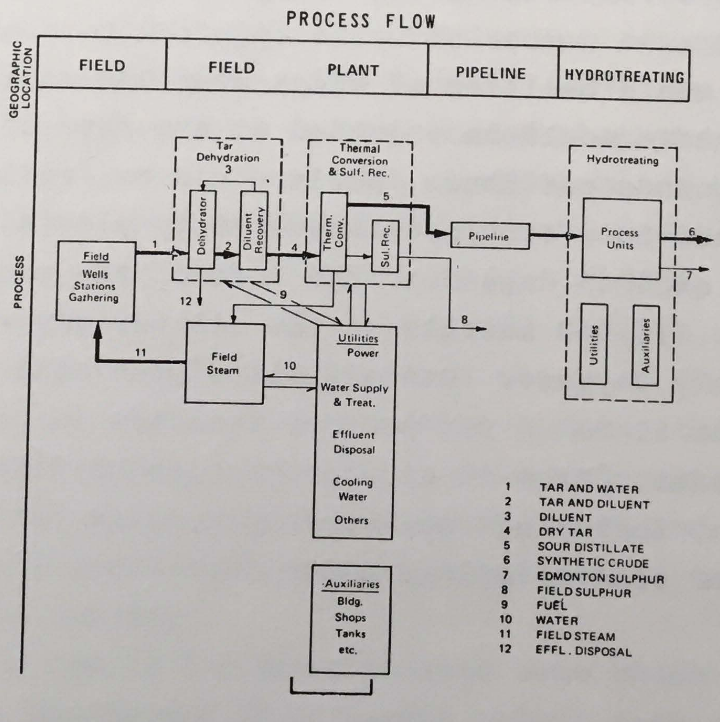

FIGURE 11: *In-situ schematic flow diagram*

than that obtainable in conventional oil-reservoirs.

Injection rate and pattern spacing are the two principal variables in the steam-drive process that must be taken into account in order to combine optimum economic results and sound conservation practices. One of the most significant factors affecting the overall economic efficiency of this process if the quantity of heat lost to the underlying and overlying formations. As the heat loss increases, the greater is the fraction of the produced oil that must be used as fuel for heating the injected fluids. The heat loss can be reduced by heating the oil-bearing sand more rapidly, by injecting steam at higher rates and by decreasing the well spacing. However, as injection rate and well density are increased, capital costs for surface and subsurface facilities increase rapidly. Also, the injectivity of steam is physically limited by the permeability and the pressure that can be applied to the formation without causing rupture in a vertical plane. On the basis of the proposed full scale operation designed to produce approximately 130,000 barrels of raw oil per day, Shell calculated that the minimum number of wells required to obtain this production would be 1,580 of which over 900 would be production wells and steam would be injected at the rate of approximately 6 million pounds per hour. Wells would be drilled, produced and abandoned in a continous sequence by placing 84 new wells on production each 58 days over the life of the project. The build-up to 130,000 barrels of raw oil per day would take approximately 3 years. Using Shell's predicted recovery efficency of 50 to 70 per cent of reserves in place, the entire operation from in-situ production to final up-grading at Edmonton, including fuel consumption, is estimated to be 28 to 38 per cent of oil in place.

FEASIBILITY OF OIL SANDS DEVELOPMENT

The interest generated in tar sands development during the war years and immediately thereafter all but ceased with the discovery of the Leduc oil field south of Edmonton in 1947. As industry enthusiasm was revived in the late 1950's and 1960's this was also dampened as a result of the restrictive government policy aimed at protecting the then limited markets for conventional Canadian oil, and by uncertainties over various tax reform proposals. Technical difficulties in extracting crude from the sands also made it too expensive to compete with lower-cost conventional oil.

Despite their incredible size in excess of 300 billion barrels of recoverable synthetic crude and being relatively close to the world's largest market, the tar sands remained relegated to a footnote in Canadian oil reserve estimates.

The proof that such a wealth of natural resources can not readily be converted into a financial bonanza is evidenced by the trials and tribulations experienced by Great Canadian Oil Sands. The company reported a loss of $680,000 for 1972 even though revenues rose to $62.3 million. Production of synthetic crude climbed to 18.6 million barrels from 15.4 million the previous year. GCOS President K.F. Heddon stated that the financial position continues to be critical as GCOS is not presently receiving a return on its $300 million investment. Not only has Sun Oil invested almost $300 million in GCOS, but it has incurred a long-term debt of another $70 million. The loss in 1972 contributes to a deficit account which at the end of 1971 totalled more than $87 million. On that data, the GCOS balance sheet still showed $78.6 million in deferred costs. By 1971 GCOS had cut its loss rate in half ($8.25 million) and the daily production rate was almost up to the authorized output of 45,000 barrels per day.

Largely due to the considerable sums which exceeded the original cost estimates, GCOS sought relief from the full impact of crown royalties payable and from additional royalties owing

to Sun Oil and Abasand Oils under the provisions of the sublease agreement for the 4,000-acre mining location. That agreement required payment of a basic royalty of 10¢ per barrel of bitumen. There were other conditions, including a 50% increase in royalty after cash flow equalled total initial investment.

In early 1970 Abasand agreed to waive 50% of its share of royalties for three years and Sun waived all of its share for a temporary period. Also in 1970, the Alberta Government began remitting 50% of the Crown royalties payable by the Company for a three-year period ending April 1, 1973. GCOS requested over a year ago that the Company be permitted to continue at the 4% royalty rate for at least two more years. The existing royalty is 8% on the first 900,000 barrels produced monthly and 20% on the balance. In addition, the Federal Government remitted $6 million, part of the sales tax collected on the price of production machinery acquired by the Company. The tax was levied just before construction began and removed just as construction ended. Neither the Alberta Government nor Abasand extended their agreements beyond April 1, and GCOS is now subject to the original level of royalties.

Of major economic importance have been the increases in the price of conventional Alberta crude, which has allowed GCOS to benefit from similar increases. The combined 30 cents a barrel increase in November 1972 and early in 1973 and the more recent 25 cent increase in May have contributed significantly to improving the overall economics of tar sands exploitation.

Mining the tar sands is capital-intensive as the capital investment required for oil sands processing plants is in the order of $6,000 to $7,000 per barrel per day producing rate. Thus, $700 million will be required for each 100 to 125,000 barrel per day plant. Barring last minute changes, Syncrude is expected to make a firm commitment to commence its project with production slated for 1977. Cost is estimated in the order of $650 to $700 million excluding the power plant and pipeline.

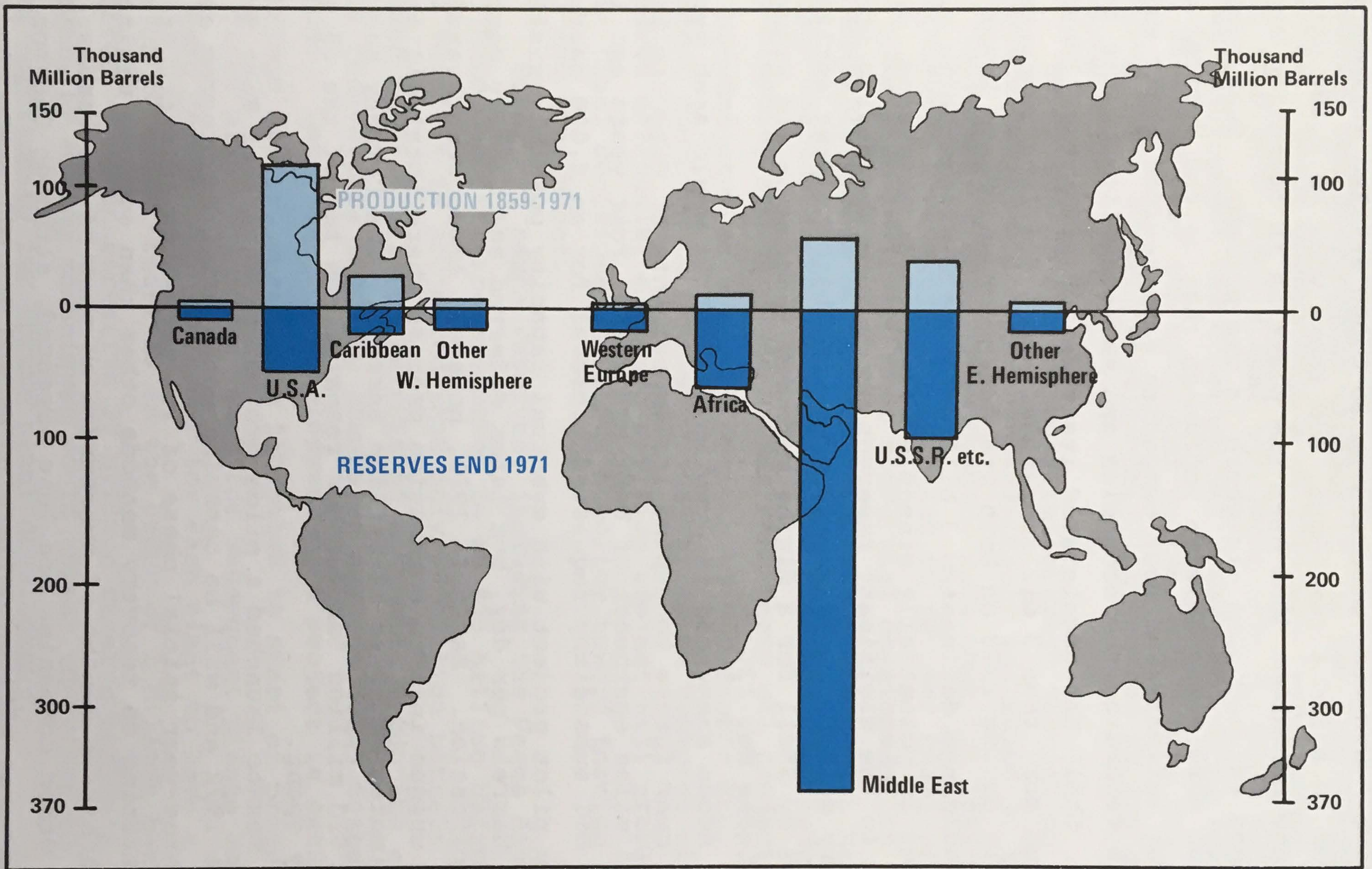

FIGURE 12: *Total discovered oil showing production and reserves to the end of 1971 (source:BP)*

Mining and processing the tar sands is also very labor-intensive. Syncrude predicts up to 2,500 skilled workmen will be required to build a new plant, and there will be 1,100 direct in-plant new permanent jobs once the plant is in operation and 7,900 permanent related jobs elsewhere in the economy. Such plants are much more vulnerable to inflation that is the typical oil field or refinery and most companies have revised their estimates upwards regarding the economics and marketability of the tar sands. Shell has accelerated its research efforts on leases covering more than 3 million areas. Core drilling conducted by Shell during 1972 on both its Athabasca and Peace River tar sands holdings delineated 3 billion barrels of synthetic crude reserves in potentially mineable orebodies at Athabasca, in addition to the sigificant reserves producible by in-situ thermal recovery methods. It is very probable that the next application will be by Shell for a mining recovery program on its Bituminous Sands Lease No. 13.

Amoco announced in June 1972, that it would seek permission in the near future to expand its experiments at Gregoire Lake, some 25 miles southeast of Fort McMurray. Four years ago its Muskeg Oil subsidiary requested approval for an 8,000 barrel per day pilot project with eventual capacity possibly rising to 60,000 barrels per day, but later deferred and finally cancelled the application. Early in 1971, however, Amoco reactivated work on its unique in-situ combustion process where total oil in place is estimated at 13 to 14 billion barrels. The Company has earmarked $13 million for further research, on top of the $9 million already spent.

Texaco launched a pilot project southeast of Fort McMurray in June 1972 and will be carrying out a drilling program as part of a three-year initial phase of its tar sands effort. It too is concentrating on recovery methods other than surface mining, due to prohibitive depths of overburden on most of its leases.

Other companies are less advanced, although Chevron has spent several million dollars to extend its oil sands holdings

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along the Athabasca River near GCOS, and Petrofina has started evaluation and development studies of its own "near-surface" reserves. Union bought into a 50,000-acre lease across the river from GCOS under a June agreement with Burmah's Great Plains Development and Colorado Oil & Gas, and plans further core drilling over the next year or two, while Home Oil is carrying out a 69-well shallow drilling program on its own holdings.

BP Canada is continuing stratigraphic testing on its Athabasca leases which were substantially increased by the merger with Supertest, although the Company says that its 1966-70 experimental steam-injection project to recover heavy oil in the Cold Lake area indicated that commercial development is not economically viable at present. Other companies with Athabasca acreage include Husky Oil - which has previous experience in fire-flooding recovery techniques with heavy oil production in the Lloydminster area - and Continental's Hudson's Bay. The Japanese continue to discuss joint tar sands ventures with Canadian officials, although any firm project will probably await final decisions on Ottawa's policy toward foreign ownership and investment.

Total tar sands reserves, including the Peace River and Cold Lake deposits are estimated to be 895 billion barrels. Of this total it is projected that only 38 billion barrels of bitumen or 26.6 billion barrels of synthetic crude are economically recoverable from the Athabasca deposit using tested mining methods. Lead time for development of a project is estimated at a minimum of five years from inception to start of production for the first plant and three years for subsequent plants employing the same technology. In order for each plant to have a productive life of 20 years, reserves in the order of 1 billion barrels are required. The conservative 27 billion reserve estimate for recovery by mining techniques would appear therefore to leave ample opportunity for future plant development.

Although most attention is presently being focused on

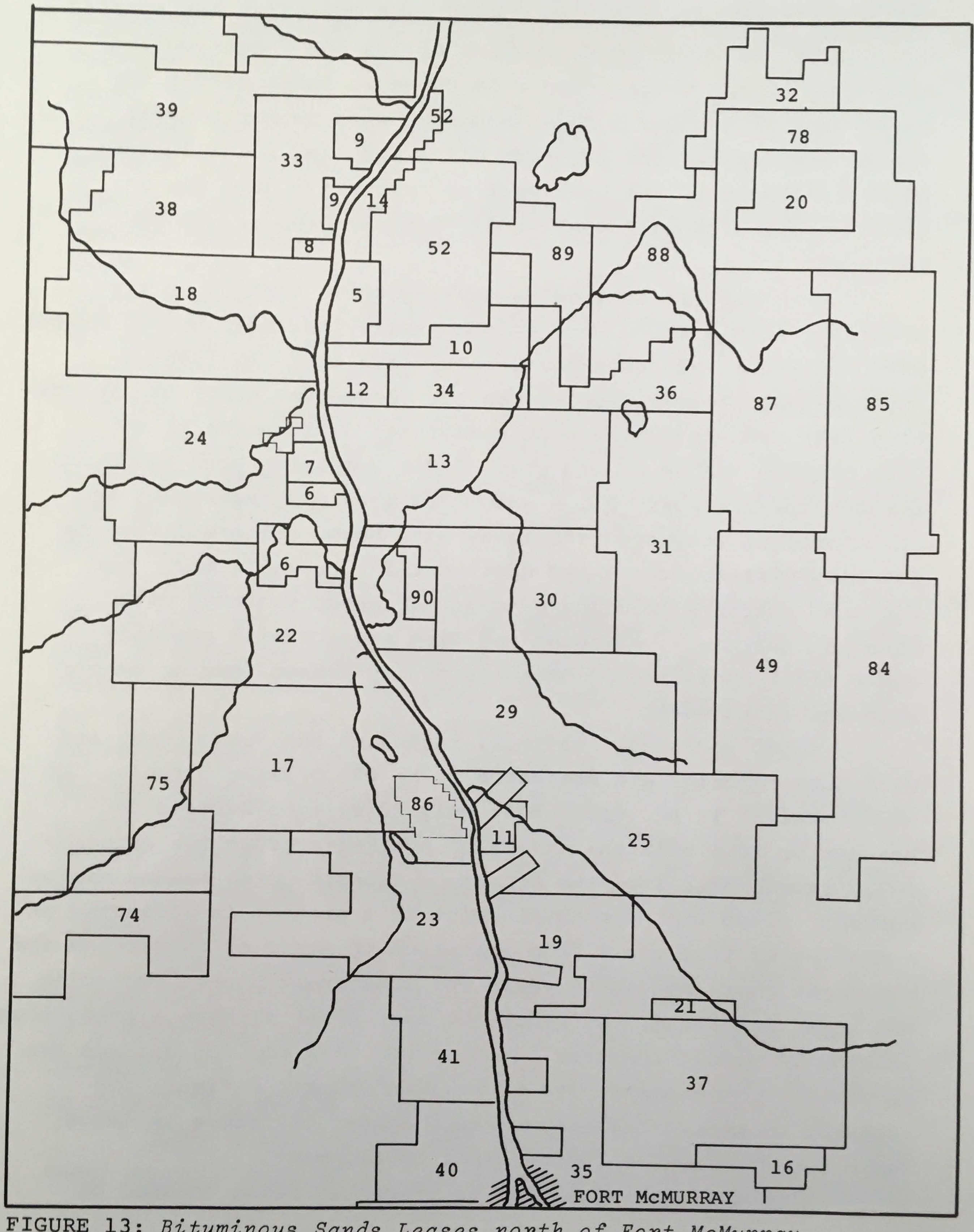

FIGURE 13: *Bituminous Sands Leases north of Fort McMurray*

BITUMINOUS SANDS LEASES COMPANY	BITUMINOUS SANDS LEASES NUMBER
Amerada Petroleum Corporation	- 88, 89, 90
Aquitaine Company of Canada Ltd., and Elf Oil Exploration & Production Canada Ltd.	- 39
Atlantic Richfield Canada Ltd.	- 52, 74, 75
Bailey Selburn Oil & Gas Ltd., and Whitehall Canadian Oils Ltd.	- 19, 20
BP Canada Limited	- 24
Canadian Fina Oil Limited	- 6, 7, 8, 9, 11, 12, 33, 34
Can-Amera Export Refining Company Ltd.	- 5
Great Canadian Oil Sands Limited	- 14
Great Plains Petroleums Limited and Colorado Oil & Gas Corporation	- 25
Home Oil Company Limited	- 30
Husky Oil Canada Ltd.	- 35
Mic Mac Oils (1963) Ltd.	- 18
Mobil Oil Canada, Ltd.	- 16, 21, 36, 37, 38
Shell Canada Limited	- 13
Sun Oil Company Limited	- 10, 84, 85, 86
Syncrude Canada Ltd.	- 17, 22, 29, 31, 32, 40, 41, 78
Tenneco Oil & Minerals, Ltd.	- 87
Texaco Exploration Company	- 49
William Lester McKnight, Walter Northey Trenerry and Charles Judson Hess	- 23

mining techniques in the Athabasca deposit, it is very probable that the first commercial in-situ operations will be undertaken in the Cold Lake or Peace River deposits in the early 1980's. Imperial Oil is continuing its Cold Lake pilot and Shell has recently announced its intention to undertake a $30 million pilot project on its Peace River acreage. Although these two deposits are of considerably lesser magnitude than the Athabasca deposit, in absolute terms they represent a major source of recoverable reserves of synthetic crude oil.

POTENTIAL LIMITATION OF CANADIAN PETROLEUM SUPPLIES

In December 1972, the National Energy Board published a preliminary report on the potential limitation of Canadian petroleum supplies. In assessing the tar sands, NEB pointed out the capital-intensive nature of developing this resource and the significant delays which could result if the industry suffered from a shortage of capital, lost confidence in the economy or felt itself unduly hampered by royalty and taxation regulation. NEB classified the Athabasca future source of supply as less assured than conventional production from known reserves but in its projections of available supply allowed for a production level of 510,000 barrels per day by 1980 increasing to 1,200,000 barrels by 1985. Considering a construction lead time of 5 years it is highly improbable that production from the tar sands will attain more than 60 per cent of that forecast.

In developing these data, NEB assumed that the overall production level would be limited initially by anticipated market demand and in later years by maximum production capacity. Due to the present uncertainties of developing frontier resource such as the tar sands and the Mackenzie Delta, NEB assumed reserves of a magnitude only sufficient to support their forecast production rates and did not consider these reserves as contributing to any domestic market demand protection. Prefaced

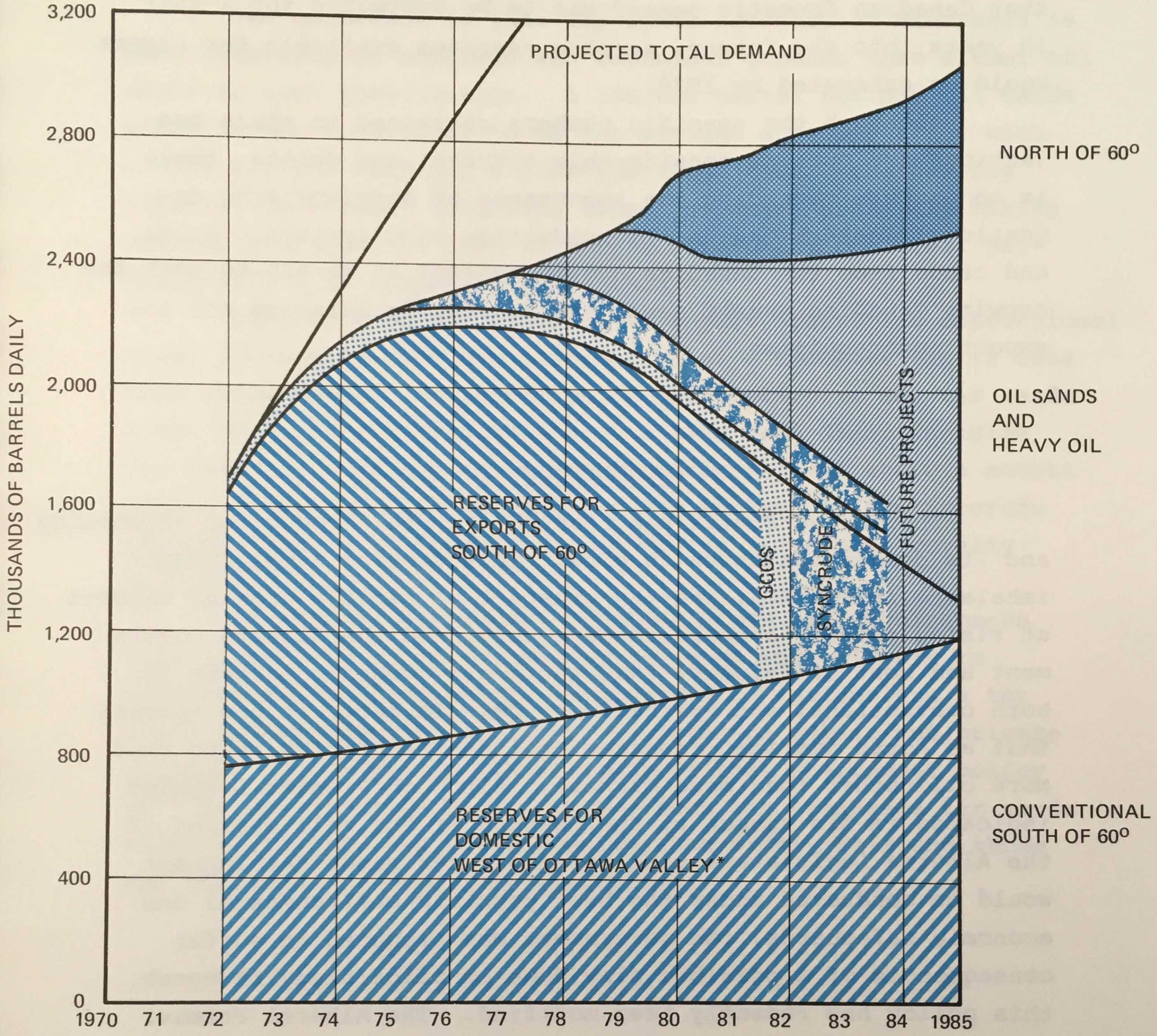

FIGURE 14: *Canadian petroleum supply/demand projections (source:NEB, December 1972)*

by these assumptions, commencing in 1974 NEB projects a productive capacity less then potential market demand. Assuming that Canadian domestic demand was to be protected for a full 15 years into the future, surplus reserves available for export would be exhausted by 1979.

Although the specific numbers contained in these projections are open to considerable argument and debate, there is no dispute regarding the importance of supplementing conventional western Canada oil production with synthetic crude and crude from the Canadian Arctic regions if we are to meet the growing Canadian energy needs and to satisfy existing and new export opportunities.

CONCLUSION

The United States has reached its peak production capability and its demand continues to grow. This growing supply/demand imbalance in the U.S. and the prospect of rapidly growing imports at rising prices, appears to have convinced the Alberta Government and most of industry that there are adequate markets for both conventional and synthetic crude. In fact, it now appears that as North American reserves decline the problem is to find more oil rather than more markets. Although Premier Lougheed indicated in his speech at the opening of the fall session of the Alberta Legislature that to ensure tar sands development would be conducted under the best possible environmental and economic safeguards, the government was prepared to suffer consequences of a possible slow down in pilot study research, this policy has recently been modified. The Alberta Premier more recently announced a further delay in the development of a long-range policy for development of the Athabasca tar sands but in the interim indicated that the government will strive for completion of the Syncrude project. Approval of other projects is likely to be done in concert with preparation of an overall

tar sands exploitation strategy and expansion of associated processing within Alberta.

The consensus is that tar sands recovery at Athabasca is more promising on economic and technical grounds than either oil shale or coal gasification. A 100,000 barrel per day oil sands plant is now considered to be the minimum economic size, with a $700 million cost and a five-year lead time. The one big question mark still troubling those companies presently making serious overtures is that of future government policies, particularily with respect to royalties.

Alberta's recent increase in royalty rates for conventional crude production with the alternative of a reserves tax is less than encouraging. An extension of this policy to the tar sands could have major ramifications at a time when Great Canadian Oil Sands is only now beginning to reach a level where a modest annual profit may be realized and the success of the Syncrude project appears to largely depend upon a favourable royalty decision.

To ensure that Canada's future crude oil requirements will be met, industry and government must work closely to overcome the many technical hurdles and to rationalize a tar sands policy that is beneficial to both the public and private sectors. There can be little question that Government policy will be the decisive factor in how soon the Athabasca tar sands begin to fulfill the great promise that Sidney Ells and those who followed him have long recognized.

APPENDIX A

Government Policy Statement with respect to Oil Sands Development

PART 1
(October 1962)

Recently the Government authorized the first commercial development of the oil sands and other applications currently are pending.

The Government has an obvious responsibility to regulate the timing and the extent of oil sands production to protect the interests of the public as the owners of this resource and to ensure that the position of conventional oil production in Alberta is not jeopardized by the loss of already limited markets to a new source of supply. No economic advantage to consumers of oil products will accrue through the development of the oil sands since synthetic crude oil from the sands and conventional crude oil will, for at least some time, be competitive.

The conventional oil industry has invested nearly four billion dollars in exploration and development in Alberta and the impact of its operations is a major factor in the buoyancy of Alberta's economy. In addition, it generates over 40 per cent of total provincial public revenues. Obviously it would be detrimental to the public interest to permit unregulated development of an alternative source of supply to impair the economic soundness of the conventional oil industry by further reducing its already limited market. This situation is aggravated by the fact that conventional oil is prorated to available market while oil from the sands cannot be so prorated because a constant plant through-put is essential to make such development economically feasible. Having regard to these circumstances, the policy of the Government will be to so regulate oil sand production that it will supplement but not displace conventional oil. At the same time, an opportunity will be provided for the orderly development of the oil sands within the limits dictated by the Government's responsibility to the public interest in preserving the stability of conventional oil development and the necessary incentive to ensure its continued growth.

For such production from the oil sands as may be able to reach markets clearly beyond present or foreseeable reach of Alberta's conventional industry, there is no need to restrict the rate of production from the oil sands and, provided the development program meets with the approval of the Oil and Gas Conservation Board, the Government will authorize it.

On the other hand, for such oil sands production as would be in competition with present or foreseeable markets for conventionally-produced Alberta crude oil, the impact on the conventional industry will be carefully considered. In this instance, the Government's judgment is that the best interests of the province will be served

(a) in the initial stages of oil sands development, by restricting production to some 5 per cent of the total demand for Alberta oil - i.e. at a level of the order of that recently approved for Great Canadian;

(b) as market growth enables the conventional industry to produce at a greater proportion of its productive capacity, by permitting increments in oil sands production as recommended by the Oil and Gas Conservation Board, and on a scale, and so timed, as to retain incentive for the continued growth of the conventional industry; and

(c) by relating the scale and timing of increments of oil sands production also to the life index of proven reserves of conventional oil allowing the index to decline gradually from present levels but ensuring that it does not drop below 12 to 13 years.

This policy will afford flexibility in application and will ensure that the orderly development of the oil sands will proceed as rapidly as their production can be integrated into the over-all oil economy of the Province.

As the Government now sees the situation, total oil sands production probably will not exceed 200,000 barrels per day by 1975 and, depending upon the total oil demand and the capacity of the conventional industry, it could be less.

All plans for oil sands development require the approval of the Oil and Gas Conservation Board. The Government will look to the Board for assistance in implementing this general policy and for guidance should it become necessary to select among competing development proposals.

In short, it is the Government's intention to assure to the conventional oil industry a rate of production and a share of available markets in excess of what currently prevails and also to ensure that a reasonable share of future increased markets will be available to conventionally produced oil. This will still give scope for the orderly development of the oil sands under a regulated program that will protect

the public interest by preventing detrimental dislocations in the Provincial economy.

PART 2
(February 1968)

There have been several developments since 1962 which have had an impact on the effectiveness and the interpretation of this policy. In 1964 the Oil and Gas Conservation Board announced the adoption of a new proration plan which has had significant effect on the development of reserves in the conventional industry.

In the years subsequent to 1962 industry's exploratory efforts have been successful. These latter discoveries added materially to the Province's crude oil reserves.

The impact of the re-assessment of older reserves, the institution of numerous enhanced recovery schemes, the new discoveries and the market circumstances have increased the life index for conventional crude oil from the 22 years of 1962 to a current level of some 31 years, rather than the 21 years previously expected.

In addition to the above developments substantial reserves of heavy hydrocarbons that have many similarities with the Athabasca type oil sands have been discovered in the general Cold Lake area. While the Oil and Gas Conservation Board recently has found these reserves to fall within the definition of "oil sands" in The Oil and Gas Conservation Act, the definition appears to require clarification. Moreover, the different definitions in various Provincial statues require standardization.

The Board advised the Government that it believed certain aspects of the present policy should be clarified and that the policy should be amended in a manner which would encourage greater market growth than would otherwise occur and by this means enable further oil sands development without prejudice to the conventional industry. It considered these important in the long term interest of the Province in the development of its natural resources and to enhance its position as a major and growing source of petroleum supply on the North American continent. Further development would ensure that the Province would be able to take full advantage of market opportunities expected with the growing supply deficiencies in the United States, and enable it to maintain its technological position as a source of synthetic crude oil having regard to potential developments elsewhere - especially in the oil-from-coal and the oil-from-shale programs in the United States. The Board suggested that certain clarifications

and one amendment could be made in the policy without change in its broad intent and presented some preliminary proposals to achieve the objective.

The Government agrees with most of the industry and the Board that there are certain features of the present oil sands development policy that require clarification. Additionally, the Government believes that the policy should be amended to encourage further growth in the total crude oil market and thereby permit further oil sands development.

The clarifications are as follows:

(1) The Government believes that the heavy oils of the Cold Lake type must be subject to the same policy as the Athabasca type oil sands. It takes this position because of the magnitude of the Cold Lake reserves in relation to conventional reserves, the similarity of the crude hydrocarbons themselves, and the probable similarity of in situ recovery methods for Cold Lake type heavy oils and Athabasca type oil sands. Moreover, the Government believes that regulation of the rate of production of the Cold Lake type heavy oils by the "approval" system used with oil sands is more practical than by prorating as is done with the light and medium crude oils. The lack of ready interchangeability among the heavy oils and the fact that by upgrading processes they, like the oil sands oil, could compete in the market for light and medium crude oil suggests serious problems if the regulation of production were based on proration to market demand. Consistent with this the Government has decided that the definition of oil sands should be amended in order to remove ambiguities. Furthermore, it believes that common definitions need to be adopted in all Provincial statutes and regulations, thus ensuring a consistent mineral acquisition and development policy. The Government recognizes that because of the gradation in characteristics of the heavy oils it will be difficult to arrive at satisfactory definitions and that some arbitrariness will probably be necessary.

The Government believes that the best way of developing satisfactory definitions would be through the advice of a special committee composed of representatives from the Alberta Division of the Canadian Petroleum Association, the Independent Petroleum Association of Canada, the Department of Mines and Minerals and the Oil and Gas Conservation Board. The Board will be asked to convene such a committee.

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(2) There needs to be clarification of what markets would be considered "beyond present and foreseeable reach of Alberta's conventional industry". The Government believes that the distinction between "within reach" and "beyond reach" markets should not be confined to a geographical one but that "beyond reach markets" should include any markets, including specialty markets, which Alberta"s conventional industry is not now serving nor can reasonably be expected to serve in the foreseeable future because of price, quality specification or other reasons. Decision in an actual case might be based on the recommendation of the Board following the public hearing of an application.

(3) With respect to an application proposing the marketing of oil sands production within reach of the conventional industry, but not in "new" markets as defined later, the Government believes that, as at present, the application should be approved only when indicated to be desirable on the basis of the trend in the life-index of the conventional industry. However, the criterion of per cent utilization of productive capacity referred to in the present policy is no longer useful and will be discarded.

(4) With respect to an application proposing the marketing of oil sands production in markets that are beyond reach of the conventional industry, the present policy is satisfactory and will be continued with such production being unrestricted so long as the development program meets the conservation and related requirements of the Oil and Gas Conservation Board.

(5) Under the present policy experimental operations in the oil sands, not involving commercial production, are encouraged and authorized by the Board and the Government without public hearing. The Government believes it desirable that this be continued and, for clarification, points out that such operations may involve temporary production and marketing of oil sands products at levels considered subcommercial by the Board.

One amendment is made in the present policy. This is discussed in the following:

(1) The Government believes that in order to encourage greater growth in the total crude oil market than would otherwise occur and thereby permit further oil sands development, the present policy requires

amendment with respect to the treatment of applications that provide for marketing a product from oil sands "within reach" of the conventional industry. Where it can be demonstrated that the applicant's marketing proposal would provide such additional growth by the development of a "new" market the Government is prepared to authorize further production of oil sands product at volumes equal to 50 per cent of the new market. A "new" market would be one not being served today; one over and above the normal growth in existing markets; and one representing a net increase in total market.

The Government believes that applications approved under this modification of the policy would provide the conventional industry with an immediate share of markets which if otherwise obtained at all would have been obtained several years later. The modification, therefore, is unlikely to have any significant adverse effect upon the conventional industry.

It is recognized that during the next few years it is particularly difficult to estimate market growth. In view of this the Government believes it desirable to establish specific limitations on the additional volume of oil sands production that would be approved under this amendment of the 1962 policy.

Accordingly, the total volume of commerical oil sands production, including the presently authorized production, that will be permitted to enter new markets within reach of the conventional industry will be restricted to 150,000 barrels per day. Unless some wholly unforeseen set of circumstances should develop, this limit will remain in effect for five years. During this period the limit will be reviewed and, if conditions warrant, it may be increased for a succeeding period.

In addition to these matters relating to the circumstances under which additional oil sands production would be authorized, the Government also has given serious consideration to the question of the royalty payable to the Crown on products derived from bituminous sands or oil sands owned by the Province. Such royalties are prescribed by regulation made under the Mines and Minerals Act, 1962. The Act authorizes the establishment of rates of royalty either of general application or with respect to any specified operation.

In January of 1963 Bituminous Sands Royalty Regulation

No. 1 was established fixing the royalty payable until March 31, 1972, on the products recovered in the operation of Great Canadian Oil Sands Limited (45,000 barrels of synthetic crude oil and some 300 long tons of sulphur per day). The present royalty is based upon the value at the plant site of these products and the rate averages out at about 12 per cent on the synthetic crude oil and is 16 2/3 per cent on the sulphur. (The total royalty is equivalent to some 20 per cent of the value of the raw bitument from which the synthetic crude oil and sulphur are derived.).

The Government has decided that when the present royalty arrangement with Great Canadian is reviewed, and in the case of any other commercial development of oil sands, it will express the royalty as one applicable to the raw bitumen recovered, at its value at the recovery site. This change in basis will result in comparable royalty treatment regardless of the extent of upgrading and will ensure that there will be no royalty incentive against extensive upgrading of the bitumen in Alberta.

Whether the future royalty rate on the raw bitumen will be altered from one which would yield the same return as under the present arrangements with Great Canadian will depend on future circumstances and whether any changes are found necessary in royalty rates as they apply to the production of Provincially-owned oil and gas generally.

In considering the royalty rate expressed on the raw bitumen basis during the first term of a Crown lease, the Government would bear in mind the provision of the lease and The Mines and Minerals Act, 1962 relating to the maximum royalty rates applicable, during the first term of the lease, to the products derived from bituminous sands or oil sands. The total royalty would not exceed that which could be fixed under these limits.

Crown royalties applicable to crude oil produced from wells have in the past been set for periods of 10 years, the last regulation coming into effect on April 1, 1962. Accordingly, the next general review of royalty rates will be in 1972.

APPENDIX B

Crude Bitumen and Synthetic Crude Oil

Proved Reserves

Starting with this year's publication the Board has decided to provide its current interpretation of the proved reserves of crude bitumen and synthetic crude oil attributable to the major oil sands deposits in Alberta. The Board issued an appraisal of the reserves of the Athabasca and certain other deposits in 1963[1] and a technical paper[2] prepared by Mr. H. J. Webber of the Board staff described the reserves in the Cold Lake deposits. The Board has recently updated its Cold Lake study and this will be reported upon in detail later in 1973.

The aforementioned studies related largely to the determination of the proved initial in place reserves of crude bitumen. The Athabasca study did include a broad estimate of the ultimate recoverable synthetic crude oil but, since the study predated commercial development, recoverable reserves in the proved category were not identified. The commercial production of some 62 million barrels of synthetic crude oil over the past 5 years now makes it possible to identify the proved reserves recoverable by mining and surface extraction methods.

The major deposits of oil sands have been designated by the Board through oil sands deposit (OSD) orders and include the Athabasca, Buffalo Head Hills, Peace River and Wabasca A deposits described in the 1963 publication and the Cold Lake A, B and C deposits and the Wabasca B deposit more recently defined by drilling and geological evaluation. The location and areal extent of the various deposits is shown in Table B-1.

In its appraisal of the Reserves of crude bitumen and synthetic crude oil the Board has used its new reserves terminology as described earlier in this report. In the evaluation

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1 A Description and Reserves Estimate of the Oil Sands of Alberta. Oil and Gas Conservation Board. October 1963.

2 Webber, H. J.; "The Oil Sands of Alberta", 18th Annual Technical Meeting, The Petroleum Section of C.I.M., Banff, Alberta, May, 1967.

of the in place reserves a minimum saturation cut-off of 2 weight per cent crude bitumen was used for the deposits studied in 1963 and a cut-off of 3 weight per cent has been applied to the more recently studied deposits.

The first few columns of Table B-1 identify the deposits, present certain basic data and indicate the proved initial in place reserves of crude bitumen. The total proved initial in place reserves are estimated to be 895 billion barrels.

Table B-1 also presents, for overburden depth intervals of 0-50, 50-100 and 100-150 feet for the Athabasca deposit, the Board's estimate of the fraction of the in place crude bitumen which will be recovered and the proved initial recoverable reserves of crude bitumen. The Board considers, as a result of the experience of Great Canadian Oil Sands Limited and the studies of Syncrude Canada Ltd., that recovery of crude bitumen by mining operations is proved to an overburden depth not to exceed 150 feet provided that the ratio of overburden depth to average pay thickness does not exceed 1.0. The limiting overburden to pay ratio reflects current recovery economics and technology and what may reasonably be anticipated in the near future. For the purpose of evaluating the reserves recoverable by mining operations the Board discounted the average pay thickness by that portion of the pay which had a crude bitumen saturation of 5 or less weight per cent. The decreasing crude bitumen recovery fraction with increasing overburden depth shown in Table B-1 reflect the discounting within the over-burden depth intervals of in place reserves for overburden to pay thickness ratios in excess of 1.0 and for bitumen saturation less than 5 weight per cent.

Table B-1 shows that the total proved initial crude bitumen reserves recoverable by mining operations in 38 billion barrels. The proved initial and remaining reserves of synthetic crude oil recoverable from mining operations are also shown in Table B-1 and reflect a 70 volume per cent or approximately 60 weight per cent conversion of the recoverable crude bitumen to synthetic crude oil. The total proved remaining synthetic crude oil recoverable from mining operations is estimated at 26.5 billion barrels.

Ultimate Reserves

The Board is confident that recovery of crude bitumen from the deposits with overburden in excess of 150 feet will take place in the future by one or a combination of different in-situ processes presently in fairly advanced stages of development. However, the Board considers that it would be premature to place such recoverable crude bitumen and the synthetic oil which could be recovered from it in the proved category at this time.

The Board estimates that the ultimate crude bitumen in place of the presently delineated oil sands deposits in the Province will amount to some 1,000 billion barrels. A review of potential recovery techniques and deposit characteristics leads the Board to believe that the ultimate recoverable reserves of crude bitumen are approximately 330 billion barrels and the ultimate recoverable reserves of synthetic crude are close to 250 billion barrels.

TABLE

PROVED RESERVES OF CRUDE BITUMEN

DECEMBER

DEPOSIT	OVERBURDEN DEPTH INTERVAL (FEET)	AREAL EXTENT (M ACRES)	AVERAGE PAY THICKNESS (FEET)	AVERAGE CRUDE BITUMEN SATURATION (FRACTION BY WEIGHT)	CRUDE BITUMEN SATURATION CUT-OFF (FRACTION BY WEIGHT)	INITIAL CRUDE BITUMEN IN PLACE (MMSTB)	CRUDE BITUMAN RECOVERY (FRACTION BY VOLUME)	INITIAL RECOVERABLE CRUDE BITUMEN (MMSTB)
Athabasca	0-50	80	104	0.098	.02	12,400	0.83	10,300
	50-100	210	103	0.100		32,700	0.58	18,900
	100-150	200	94	0.102		28,900	0.30	8,800
	150-250	270	112	0.102		46,500		
	250-500	590	104	0.096		88,900		
	500-1000	2,100	67	0.098		209,500		
	1000-2000	2,300	59	0.100		207,000		
Cold Lake A	1000-2000	1,800	53	0.080	.03	117,900		
Cold Lake B	1000-2000	650	40	0.081	.03	32,700		
Cold Lake	1000-2000	710	16	0.076	.03	13,500		
Buffalo	500-1000	22	6	0.050	.02	100		
Head Hills	1000-2000	131	7	0.050		700		
	2000-2500	6	21	0.050		100		
Peace River	1000-2000	360	38	0.074	.02	15,900		
	2000-2500	820	37	0.074		34,500		
Wabasca A	250-500	91	25	0.100	.02	3,500		
	500-1000	619	32	0.084		26,000		
	1000-2000	54	11	0.101		900		
Wabasca B	1000-2500	1,000	26	0.059	.03	23,400		
TOTALS		12,013				895,100		38,000

* A DESCRIPTION AND RESERVES ESTIMATE OF THE OIL SANDS OF ALBERTA - OIL AND GAS CONSERVATION BOARD - OCTOBER 1963.

NOTE: WEIGHT TO VOLUME CONVERSION FOR THE ATHABASCA DEPOSIT IS 1.95, FOR OTHER DEPOSITS IT IS ESTIMATED TO BE 2.0.

B-1

AND SYNTHETIC CRUDE OIL IN ALBERTA

31, 1972

CUMULATIVE CRUDE BITUMEN PRODUCTION (MMSTB)	REMAINING RECOVERABLE CRUDE BITUMEN (MMSTB)	SYNTHETIC CRUDE OIL RECOVERY OF CRUDE BITUMEN IN PLACE (FRACTION BY VOLUME)	SYNTHETIC CRUDE OIL RECOVERY OF RECOVERABLE CRUDE BITUMEN (FRACTION BY VOLUME)	INITIAL RECOVERABLE SYNTHETIC CRUDE OIL (MMSTB)	CUMULATIVE SYNTHETIC CRUDE OIL PRODUCTION (MMSTB)	REMAINING RECOVERABLE SYNTHETIC CRUDE OIL (MMSTB)	REMARKS	
88	10,200	0.58	0.70	7,200	62	7,100	Evaluated in 1963*	1
	18,900	0.40	0.70	13,200		13,200		2
	8,800	0.21	0.70	6,200		6,200		3
								4
								5
								6
								7
								8
							Evaluated in 1972	9
								10
							Evaluated in 1972	11
								12
							Evaluated in 1972	13
								14
							Evaluated in 1963*	15
							Average oil saturation	16
							estimated at 5 per	17
							cent by weight	18
								19
							Evaluated in 1963*	20
							Maximum oil saturation	21
							estimated to be 10 per	22
							cent by weight	23
								24
							Evaluated in 1963*	25
							Maximum oil saturation	26
							estimated to be 12 per	27
							cent by weight	28
								29
							Evaluated in 1972	30
								31
88	37,900			26,600	62	26,500		32

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Walwyn, Stodgell & Company.
A look at world energy: the Athabasca tar sands.

DATE	ISSUED TO
12/23	G. H. Agnew
MAR 7 '84	H. HUGHES APR 10 '84 (HEALTH CENTRE).
June 13/84	H. Hughes " "
JULY 6/84	" " AUG 20 '84 " "

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